**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-0141E**

SUPPLEMENTAL DIRECT TESTIMONY OF JON T. LANDRUM

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 13, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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OF PUBLIC SERVICE COMPANY OF	**)**	
COLORADO FOR APPROVAL OF ITS	**)**	**PROCEEDING NO. 21A-0141E**
2021 ELECTRIC RESOURCE PLAN AND	**)**	
CLEAN ENERGY PLAN	**)**	

TABLE OF CONTENTS

SECTION **PAGE**

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
CC	Combined Cycle
CDD	Cooling Degree Day
Commission	Colorado Public Utilities Commission
CSG	Community Solar Garden
CT	Combustion Turbine
DR	Demand Response
EAF	Equivalent Availability Factor
ECC	Economic Carrying Charge
ERP	Electric Resource Plan
EV	Electric Vehicle
GWh	Gigawatt-hour
IPP	Independent Power Producer
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
O&M	Operations and Maintenance
PACE	PacifiCorp East
PPA	Power Purchase Agreement
Public Service or Company	Public Service Company of Colorado
PVRR	Present Value of Revenue Requirements
RAP	Resource Acquisition Period
Reduced Lifetime	Reduced Lifetime for Natural Gas Generation

Acronym/Defined Term	**Meaning**
SCC	Social Cost of Carbon
V2G	Vehicle to Grid
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-0141E**

SUPPLEMENTAL DIRECT TESTIMONY OF JON T. LANDRUM

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon T. Landrum. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Manager of Resource Planning Analytics. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company"), along with the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION ("COMMISSION")?

A. Yes, I filed Direct Testimony and Attachment JTL-1 in this proceeding on March 31, 2021.[1] I provided a statement of qualifications with my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. The purpose of my Supplemental Direct Testimony is to explain the process the Company undertook to model the Commission's supplemental requests outlined in Decision No. C21-0395-I. My Supplemental Direct Testimony provides an overview of the outcomes of these requests.

Q. WHAT ADDITIONAL INFORMATION DID THE COMMISSION DIRECT THE COMPANY TO PROVIDE IN SUPPLEMENTAL DIRECT TESTIMONY?

A. The Commission requested nine additional modeling runs by the Company. These model runs include:

1. ***Extreme Summer Weather Event***. A re-dispatch of the Company's Preferred Plan in 2030 with a modified 2030 peak demand profile reflecting an extreme heat event where a new system peak demand is assumed to result from temperatures at least eight degrees Fahrenheit above the highest temperature recorded to date in the Company's service territory.[2]

2. ***Limited Life of New Gas Resources***. A capacity expansion run of the Preferred Plan using an expected life of 20 years for new gas resources and not permitting gas resources to extend beyond 2050.[3]

3. ***High Electric Vehicle ("EV") and Vehicle to Grid ("V2G")***. An analysis of a high penetration of EVs with a significant portion of "bi-directional" EVs.[4]

[1] Hearing Exhibit 105, Direct Testimony and Attachment of Jon T. Landrum.
[2] Decision No. C21-0395-I, at ¶ 6.
[3] Decision No. C21-0395-I, at ¶ 7. The Company applied these parameters (i.e., 20-year life limitation and no operations beyond 2050) to both Company-owned and Independent Power Producer ("IPP")-owned resources.
[4] Decision No. C21-0395-I, at ¶ 8.

4. ***Increased Bi-directional Transfer Capability***. A revised capacity expansion of the Preferred Plan that captures reserve margin and other benefits of a 400 megawatt ("MW") increase in the transfer capability between Public Service and the PacifiCorp East ("PACE") area.[5]

5. ***Shift in Peak Demand.*** A revised capacity expansion run of the Preferred Plan that shows the impact of shifting the time of system peak two hours earlier and later.[6]

6. ***Modified Comanche 3 Operations and Maintenance ("O&M") Costs and Availability*****.** Adopting the average O&M costs and availability from 2010 through 2020 for Comanche 3 and rerunning the 16 capacity expansion plan portfolios (i.e., 8 developed with \$0/CO_2 and 8 with the social cost of carbon ("SCC") applied as a carbon proxy value).[7] In addition, the Commission directed the Company to explore the impacts of economic commitment and seasonal operations on Comanche 3.[8]

7. ***Increased Community Solar Garden ("CSG") Capacity.*** The impact of an increase in CSG of 50 MW per year for four years starting in 2023, for a total increase of 200 MW of CSGs over the Company's Base Case assumptions.[9]

8. ***Increased Demand Response ("DR") Capacity.*** The impact of an increase in DR of 50 MW per year for four years starting in 2023, for a total increase of 200 MW of DR over the Company's Base Case assumptions.[10]

9. ***Higher High Gas*****.** Modeling changes in the capacity expansion plan for the Company's Preferred Plan by doubling the rate of growth in gas prices from 2026 through 2030 as against the values contained in the high gas forecast sensitivity filed in the Company's direct case.[11]

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[5] Decision No. C21-0395-I, at ¶ 9.
[6] Decision No. C21-0395-I, at ¶ 10.
[7] Decision No. C21-0395-I, at ¶ 11.
[8] Decision No. C21-0395-I, at ¶ 11.
[9] Decision No. C21-0395-I, at ¶ 12.
[10] Decision No. C21-0395-I, at ¶ 12.
[11] Decision No. C21-0395-I, at ¶ 13.

Q. HOW IS THE COMPANY ADDRESSING THESE ADDITIONAL TOPICS IN ITS SUPPLEMENTAL DIRECT FILING?

A. The majority of the discussion concerning the model setup and results for these requests is contained in my Supplemental Direct Testimony. I am the sponsor of the results of the modeling and discussion of any setup necessary to effectuate the modeling. For each requested analysis, I first describe the setup of the modeling. I then discuss the results and provide an interpretation and commentary, as appropriate. Company witness Mr. Jack W. Ihle provides some policy framing and qualitative discussion for this exercise for the High EV and V2G, increased bi-directional transfer capability, Comanche 3, CSG, and DR requests.

Q. WHAT TYPE OF MODELING DID THE COMPANY RUN FOR THESE SUPPLEMENTAL REQUESTS.

A. For requests[12] 2, 3, 4, 6, 7, 8 and 9, the Company ran a production costing model with a revised expansion plan that provided updated costs and emissions results. For request 1, the Company ran a production costing model that redispatched the Preferred Plan portfolio system for July 2030. For request 5, the Company generated a revised expansion plan for the shift in peak demand.

Q. DOES YOUR SUPPLEMENTAL DIRECT TESTIMONY SERVE ANY ADDITIONAL PURPOSE?

A. Yes. In the preparation of this Supplemental Direct Testimony, the Company discovered certain errors within the modeling which we believe it is now

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[12] As numbered at pages 6-7 of this Supplemental Direct Testimony.

appropriate to bring forward. I will discuss these issues and how the correction flows through the Company's direct case.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. No.

II. EXTREME SUMMER WEATHER EVENT

Q. HOW WAS THE LOAD IMPACT OF THE EXTREME SUMMER WEATHER EVENT MODELED?

A. The load impact of the extreme summer weather event was modeled using the weather-load relationships the Company used in the Base Case model. The Company uses cooling degree days ("CDD") with a base of 65 CDD in its modeling of energy and peak demand. Monthly energy is based on monthly CDDs, and the monthly peak demand is based on the CDDs[13] on the day of the peak. To estimate the additional energy resulting from the event, the Company assumed there were 100 additional CDDs in July 2030 and ran its sales and energy models. To estimate the additional peak demand resulting from the event, the Company added 10 CDDs to the peak day weather and calculated the new peak demand. For the peak demand impact, the Company also considered the effect of air conditioner saturation, which results in less additional load due to weather above a certain temperature since most air conditioners are already running. The Company then compared the new energy and peak forecasts to the Base Case forecasts to determine the impact of the extreme summer weather event. Finally, the Company created an hourly load profile for July 2030 that includes the higher energy and peak demand.

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[13] A Cooling Degree Day is the number of degrees a day's average temperature is above 65° Fahrenheit, for example, a day averaging 75° F would have 10 Cooling Degree Days.

Q. DID THE COMPANY ASSUME ANY CHANGES IN CUSTOMER UPTAKE OF AIR CONDITIONER INSTALLATIONS LEADING UP TO THIS EVENT?

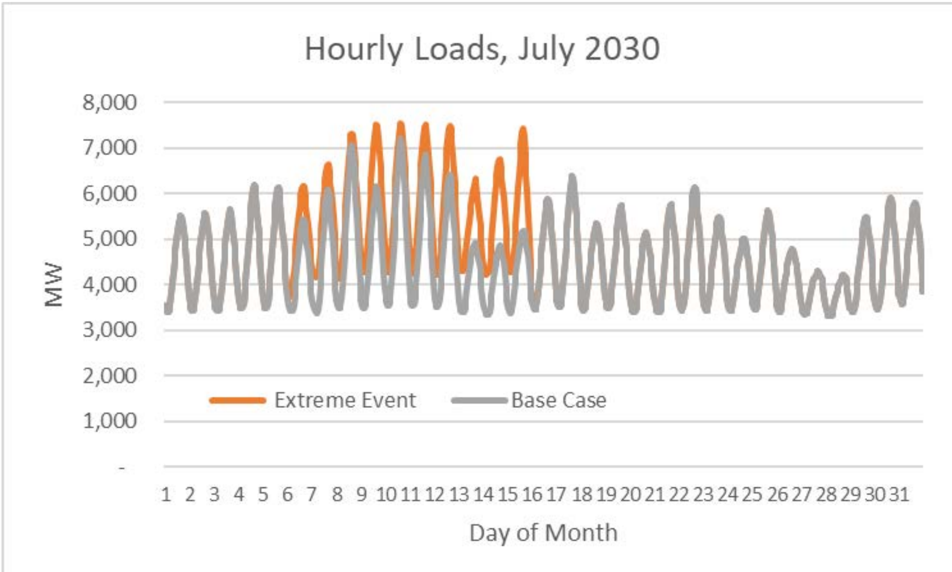
A. No. We held the assumptions on the percentage of customers with air conditioning the same in 2030 here as in our direct case, i.e., at 72 percent. The Company believes this assumption is consistent with the Commission's direction to perform this scenario as a stress test of the current portfolios without allowing additional capacity expansion. In other words, just as the Company's system planners and the Commission through the Electric Resource Plan ("ERP") process did not anticipate and build the system to this hypothetical 2030 event, neither did customers increase their installations of air conditioning in anticipation of it.

Q. HOW DID THE JULY 2030 LOAD FORECAST CHANGE DUE TO THE EXTREME SUMMER WEATHER EVENT?

A. The July 2030 energy forecast increased by 214 gigawatt-hours ("GWh") (6.4 percent) to 3,571 GWh and the peak demand forecast increased by 317 MW (4.4 percent) to 7,536 MW due to the extreme summer weather event. Figure JTL-SD-1 below compares the hourly load profiles for the Base Case and Extreme Summer Weather Event forecasts.

FIGURE JTL-SD-1

Hourly Loads, July 2030



Q. WHAT WERE THE RESULTS OF THE ENCOMPASS MODELING FOR THIS SCENARIO?

A. The modeled Extreme Summer Weather Event increased July 2030 load by approximately 214,000 megawatt-hours ("MWh") over the ten-day period. Most of the increased load was covered by a 202,000 MWh increase in generation, largely consisting of an increase in gas generation to cover the increased demand, but also including less curtailed renewables. In the Preferred Plan, approximately 8 percent of renewable generation was curtailed, with around 60 percent of the curtailments coming from wind. In the Hot July scenario, the total curtailments were reduced to around 6 percent of renewable generation, with 75 percent of the reduced curtailments occurring on wind units. Coal generation decreased, most likely driven by the increased committed (online) gas resources needed to serve the peak loads. Additionally, 12,000 MWh of the increased load was covered by less net economy market interaction (2,000 MWh less purchases and 14,000 MWh less sales), consistent with the Commission directive to "limit the availability of purchased power."[14] The changes in the generation and load are shown below in Table JTL-SD-1.

Table JTL-SD-1

	MWhs
Change in Load	214,253
Net Change in Market Purchases/Sales	12,104
Change in Generation	202,156
Change in Coal	(23,606)
Change in Gas	174,830
Change in Renewables	52,936

Q. WHAT WAS THE IMPACT ON SYSTEM RELIABILITY?

A. There was no change to unserved energy (curtailed load). Emergency purchases, which are the modeling construct representing non-economic short-term purchases needed to maintain system reliability, increased from zero to 2,500 MWh. Operating Reserve violations were largely not impacted, increasing from zero to 1 MWh, and Regulation (Flex Reserves) violations increased from 1 MWh to 273 MWh. Overall, the system was able to meet the increased load in a reliable manner using the resources identified in the Preferred Plan. The Company's Commercial Operations group confirmed the hourly dispatch of the system during the Extreme Summer Weather Event is reasonable and reliable.

[14] Decision No. C21-0395-I, at ¶ 6.

III. REDUCED LIFETIME FOR NATURAL GAS GENERATION

Q. HOW WAS THE REDUCED LIFETIME FOR NATURAL GAS GENERATION (“REDUCED LIFETIME”) SCENARIO MODELED?

A. The Company created the scenario using the baseload plan from the Company’s Preferred Plan (SCC 7) with Pawnee converted to gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The Company terminated all new added generic thermal resources by 2050 and represented the thermal generic costs inclusive of an accelerated depreciation to recover the full cost of the resource in 20 years, or by 2050, whichever is earlier. In other words, generic thermal resources that were added in or before 2030 were modeled with a 20-yearbook/service life, while resources added in 2031 were modeled with a 19-yearbook/service life, resources added in 2032 were modeled with an 18-yearbook/service life, and so on. Existing owned and power purchase agreement (“PPA”) resources were maintained at their currently assumed retirement/expiration dates, regardless of whether they extended beyond 2030 or not. All other data in the model was kept the same as what was filed in the Company’s direct case, and a new capacity expansion plan was created.

Q. WHAT WERE THE RESULTS OF THE REDUCED LIFETIME SCENARIO?

A. The model selected an optimized resource acquisition period (“RAP”) expansion plan that selected 100 MW more storage, 400 MW more wind, and 100 MW more solar, while selecting 400 MW less CTs, and 100 MW less reciprocating engine capacity. The year-by-year differences in the “Reduced Lifetime for Natural Gas Generation” plan versus SCC 7 are shown in Table JTL-SD-2 below:

TABLE JTL-SD-2

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Limited Life Gas	Standalone Storage	500	-	-	-	-	-	500
Limited Life Gas	Wind	1,000	150	200	850	500	-	2,700
Limited Life Gas	Solar	-	-	800	200	0	650	1,650
Limited Life Gas	CT	-	-	-	784	-	-	784
Limited Life Gas	Aero	-	-	-	-	-	-	-
Limited Life Gas	Recip	-	-	-	-	-	-	-
Limited Life Gas	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	300	-	-	-	-	(200)	100
Delta	Wind	-	150	50	200	350	(350)	400
Delta	Solar	-	-	200	100	0	(200)	100
Delta	CT	-	(392)	(196)	196	-	-	(392)
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. With shorter lives, gas-fired resources are less cost-effective. Therefore, less gas-fired resources are selected, and they are replaced with wind, solar, or storage. However, even with the significantly shortened plant lifetime assumptions, the model is selecting gas resources. This should provide reassurance that continued use of combustion turbines ("CTs") in the expansion plan is supported, even with the shortened plant lives. Under this scenario, even if the hydrogen pathway for gas resources the Company has assumed from 2040 to 2050 does not come to pass, the selection of gas resources in this RAP is an economically sound choice.

Q. WHAT WERE THE COST AND CARBON IMPACTS OF THIS SCENARIO?

A. Overall, the plan was significantly higher cost than the Preferred Plan. Although the Reduced Lifetime scenario selected less CT resources in the RAP, those resources were at a significantly higher cost per unit due to the change to a 20-year amortization/life versus the default 40-year assumption with hydrogen conversion beginning in 2040. Additionally, the Reduced Lifetime scenario selected two 720 MW combined cycle ("CC") units in 2032 and 2036 that were not in the Preferred Plan's long-term expansion plan.[15] The total gas capacity in both plans were substantially equivalent in 2032-2040. For simplicity and timing reasons, the EnCompass generic costs modeled as an Economic Carrying Charge ("ECC") stream were used in this analysis, and the step performed for much of the Phase I scenarios where half of the generics were switched to a capital revenue requirements representation was omitted. Even with this simpler approach, the model still shows the impacts associated with shorter natural gas lives. This step mainly affects annual cost deltas and has minimal-to-no impact on net present value ("NPV") results as both the ECC and capital revenue requirements NPV to the same result by design. The cost comparison (NPVs are 2021-2055) is shown below in Table JTL-SD-3.

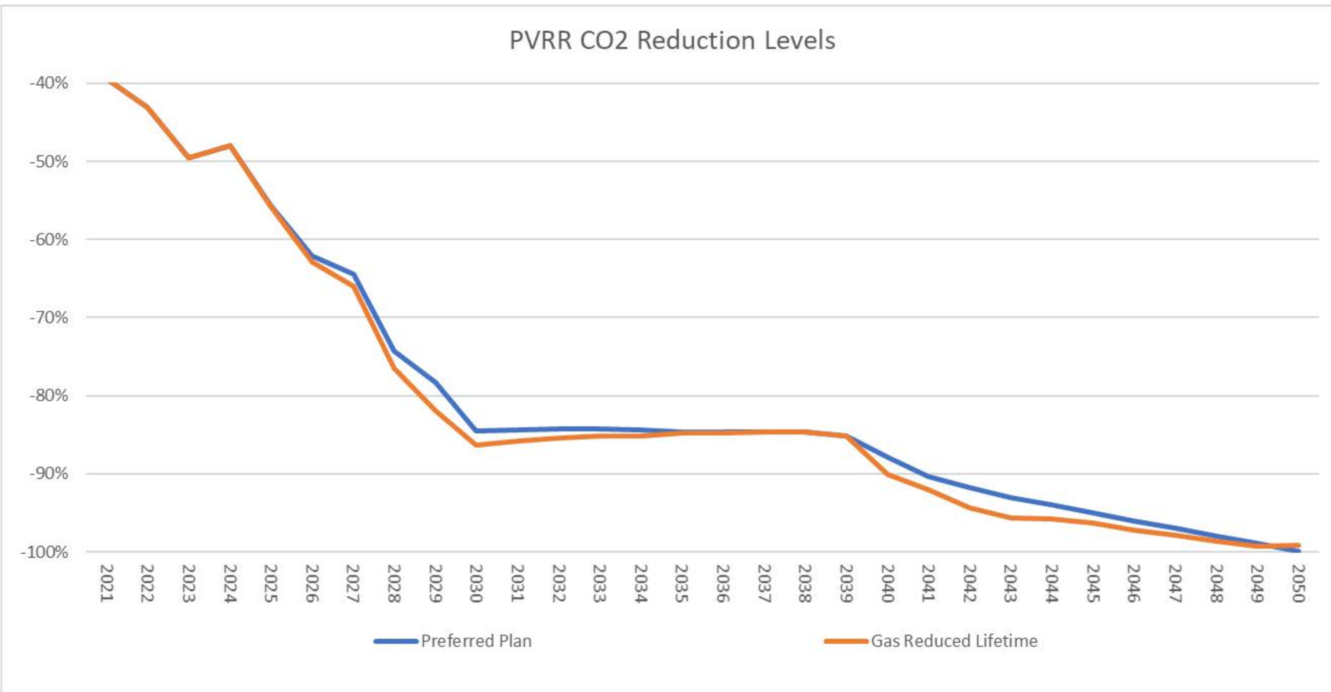
TABLE JTL-SD-3

	$2021 Millions
NPV EnCompass Cost (Savings)	$3,699
NPV CO2$, SCC Cost (Savings)	($269)
PVRR + NPV CO2 Cost (Savings)	$3,430

[15] These CCs are not shown in Table JTL-SD-2 because the model selected them outside the RAP.

The carbon emissions are marginally lower in the Reduced Lifetime scenario, but relatively similar over the Planning Period, averaging about 270,000 tons/year less. A graph of the carbon difference is shown below in Figure JTL-SD-2.

FIGURE JTL-SD-2



IV. HIGH EV AND VEHICLE TO GRID CAPACITY AND ENERGY

Q. HOW WAS THE HIGH EV/V2G SCENARIO MODELED?

A. The Company created the scenario using the baseload plan from the Company's Preferred Plan (SCC 7) with Pawnee converted to gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The High EV assumptions from the Roadmap Load Forecast (the Company's high load scenario) from the Company's direct case filing were used. In addition, 156,000 V2G-capable vehicles, bringing a total of 456 MW and 2,188 MWh of "achievable" battery energy storage, were assumed by 2030.[16] The Company assumed V2G began in 2026 at 12.5 percent of the 2030 values, grew in 2027 to 25 percent of the 2030 values, and increased by 25 percent of the 2030 values every year after until fully installed in 2030, where it is then held constant through the end of the planning period. All other data in the model was kept the same as what was filed in the Company's direct case, and a new capacity expansion plan was created.

Q. WHAT WERE THE RESULTS OF THE HIGH EV/V2G SCENARIO?

A. The model selected an optimized RAP expansion plan that selected 200 MW less generic storage, 450 MW more wind, and 200 MW less CTs and 100 MW less reciprocating engine capacity. The year-by-year differences in the "High EV/V2G" plan versus SCC 7 are shown in Table JTL-SD-4 below:

[16] Mr. Ihle's Supplemental Direct Testimony further explains the development of these assumptions.

TABLE JTL-SD-4

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
High EV V2G	Standalone Storage	200	-	-	-	-	-	200
High EV V2G	Wind	1,000	300	100	800	300	250	2,750
High EV V2G	Solar	-	350	350	0	0	1,000	1,700
High EV V2G	CT	-	-	588	588	196	-	1,372
High EV V2G	Aero	-	-	-	-	-	-	-
High EV V2G	Recip	-	-	-	-	-	-	-
High EV V2G	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	-	-	-	-	-	(200)	(200)
Delta	Wind	-	300	(50)	150	150	(100)	450
Delta	Solar	-	350	(250)	(100)	(0)	150	150
Delta	CT	-	(392)	392	-	196	-	196
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. The impact of the High EV load is about 130 MW in peak demand by 2030, and this incremental need is more than offset by the additional V2G storage added to the model, which has a firm capacity of 230 MW in 2030. With the V2G capability (i.e., storage) already embedded in the portfolio, the additional resources selected are weighted more towards additional wind and solar, and less towards generic storage. The wind and solar are likely added to meet the incremental energy needs of the High EV load, while still meeting the 2030 clean energy target.

Q. WHAT WERE THE COST AND CARBON IMPACTS OF THIS SCENARIO?

A. Costs for the increased V2G “program” are unknown and were not included in the modeling. Additionally, the increased load in the model from the High EV forecast increases total system costs simply due to serving higher capacity and energy needs than the base assumptions. Accordingly, a cost comparison was not performed. This scenario was also required to achieve the same clean energy targets as the base scenario, and simply added incremental generic renewables to achieve this result. Overall, the carbon emissions averaged around 80,000 tons per year higher than the Preferred Plan.

V. INCREASED BI-DIRECTIONAL TRANSFER CAPABILITY

Q. HOW WAS THE INTERREGIONAL TRANSMISSION INTERCONNECTION SCENARIO MODELED?

A. The Company created the scenario using the baseload plan from the Company's preferred plan (SCC 7) with Pawnee converted to gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The Company assumed 400 MW of incremental transmission interconnection to PACE and decreased the planning reserve margin to 14.06 percent starting in 2028. All other data in the model was kept the same as what was filed in the Company's direct case, and a new capacity expansion plan was created.

Q. WHAT COST FOR THE INCREMENTAL 400 MW OF TRANSMISSION DID THE COMPANY ASSUME IN ITS ANALYSES?

A. The Company assumed a new transmission interconnection to the PACE system would have an overnight capital cost of $269 million, as explained in more detail by Company witness Mr. Ihle.

Q. WHAT WERE THE RESULTS OF THE INTERREGIONAL TRANSMISSION INTERCONNECTION SCENARIO?

A. The model selected an optimized RAP expansion plan that selected 100 MW less storage, 300 MW more wind, 350 MW more solar, 200 MW less CTs, and 100 MW less reciprocating engine capacity. The year-by-year differences in the "Interregional Transmission Interconnection" plan versus SCC 7 are shown in Table JTL-SD-5 below.

TABLE JTL-SD-5

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Low PRM	Standalone Storage	200	-	-	-	-	100	300
Low PRM	Wind	1,000	-	100	1,000	200	300	2,600
Low PRM	Solar	-	200	450	200	0	1,050	1,900
Low PRM	CT	-	-	784	-	196	-	980
Low PRM	Aero	-	-	-	-	-	-	-
Low PRM	Recip	-	-	-	-	-	-	-
Low PRM	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	-	-	-	-	-	(100)	(100)
Delta	Wind	-	-	(50)	350	50	(50)	300
Delta	Solar	-	200	(150)	100	0	200	350
Delta	CT	-	(392)	588	(588)	196	-	(196)
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. The expanded interconnection amount enabled more renewables to be added economically, and there is a greater ability to make economic off-system sales from excess renewable energy that would have otherwise been curtailed due to load/generation balance. This provides incremental economic value in the modeling, and makes additional renewables more cost-effective. However, it is important to note that this incremental value comes from speculative market sales and purchases that may or may not materialize in real operations in the amount and revenues as projected in the model, making the perceived value more akin to a merchant position than more traditional retail/wholesale load-based resource planning practices. In addition, the modeling presumes that a liquid economic market can be accessed by construction of the approximately 60-mile incremental transmission line, as discussed in Company witness Mr. Ihle's Supplemental Direct Testimony. Lastly, much of the reduced firm dispatchable capacity and associated savings are most likely directly related to the reduced reserve margin associated with the scenario, which would need to be studied further before being implemented as a final planning criteria for the PSCo system.

Q. HOW DOES THIS SCENARIO PERFORM ECONOMICALLY?

A. The estimated costs were input into an economic pro-forma model and the estimated revenue requirements were added to the EnCompass model results for capacity expansion plan and production costs. The overall results show a $700 million NPV benefit of adding the transmission line, as shown below in Table JTL-SD-8 below. A strong driver of these modeled benefits is the 4 percent reduction in the Planning Reserve Margin embedded in this scenario, and another factor is savings associated with avoided curtailments of renewable energy. It is important to note that a majority of the modeled savings in this NPV analysis are back-loaded. More specifically, the accrued NPV savings, inclusive of carbon priced at the SCC, are $170 million in 2040, with the remaining $534 million of savings accruing in 2041-2055. With both the increased levels of overall renewable additions, and the increased amount of energy and associated carbon being sold off the Public Service system, the overall carbon emissions attributed to the

Company are reduced by around 250,000 tons per year (2026-2040). Company witness Mr. Ihle discusses additional and important considerations regarding this scenario in his Supplemental Direct Testimony.

TABLE JTL-SD-8

	$2021 Millions
NPV EnCompass Cost (Savings)	($770)
NPV CO2$, SCC Cost (Savings)	($157)
PVRR + NPV CO2 Cost (Savings)	($927)
Trans Expansion Cost	$223
Total Cost (Savings)	($704)

VI. SHIFT IN PEAK DEMAND

Q. HOW WAS THE SHIFT IN PEAK DEMAND MODELED?

A. The Company created two scenarios using the baseload plan from the Company's Preferred Plan (SCC 7) with Pawnee converted to gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. For both scenarios, the hourly load profile was shifted by a two-hour offset: (1) one scenario was shifted two hours forward; and (2) one scenario was shifted two hours backward, both from the system peak hour of the hour ending 1600 in the summer and the hour ending 1900 in the winter. This resulted in the hour of the system peak moving +/- two hours from what was originally modeled. For simplicity, the shift was for all years, beginning in 2021 and extending through the Planning Period. All other data in the model was kept the same as the initially filed case, and a new capacity expansion plan was created for both of these scenarios, consistent with the directives in Decision No. C21-0395-I.

Q. WHAT WERE THE RESULTS OF MOVING THE PEAK HOUR LATER IN THE DAY?

A. The model selected an optimized RAP expansion plan that selected 500 MW less solar and 150 MW less storage. The difference was made up by adding 150 MW more wind and 392 MW more gas-fired CT capacity. The year-by-year differences in the "shifted peak" plan versus SCC 7 are shown in Table JTL-SD-9 below:

Table JTL-SD-9

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Shift Peak + 2HR	Standalone Storage	150	-	-	-	-	100	250
Shift Peak + 2HR	Wind	1,000	300	-	650	150	350	2,450
Shift Peak + 2HR	Solar	-	50	250	50	0	700	1,050
Shift Peak + 2HR	CT	-	-	588	588	392	-	1,568
Shift Peak + 2HR	Aero	-	-	-	-	-	-	-
Shift Peak + 2HR	Recip	-	-	-	-	-	-	-
Shift Peak + 2HR	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	(50)	-	-	-	-	(100)	(150)
Delta	Wind	-	300	(150)	-	-	-	150
Delta	Solar	-	50	(350)	(50)	(0)	(150)	(500)
Delta	CT	-	(392)	392	-	392	-	392
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. When the peak is moved later in the day, nearer to or possibly even after sunset, solar is less able to contribute to the peak load hours on the system; therefore, the solar generation is less economic. In the Preferred Plan, batteries were at least partially utilized to shift solar energy to later in the day, and with less solar in the Shift in Peak Demand sensitivity, there is less need for storage. The model also increased the level of gas-fired resources, likely compensating for the reduced firm capacity provided by solar and storage.

Q. WHAT WERE THE RESULTS OF MOVING THE PEAK HOUR EARLIER IN THE DAY?

A. In contrast to moving the peak later in the day, when the peak was moved earlier in the day, the model selected 350 MW more solar and 100 MW more storage. This was balanced by less wind and less gas. The changes in the plan are shown below in Table JTL-SD-10:

Table JTL-SD-10

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030		Total
SCC 7	Standalone Storage	200	-	-	-	-	200		400
SCC 7	Wind	1,000	-	150	650	150	350		2,300
SCC 7	Solar	-	-	600	100	0	850		1,550
SCC 7	CT	-	392	196	588	-	-		1,176
SCC 7	Aero	-	-	-	-	-	-		-
SCC 7	Recip	-	-	-	-	100	-		100
SCC 7	CC	-	-	-	-	-	-		-
Shift Peak - 2HR	Standalone Storage	350	-	-	-	-	150		500
Shift Peak - 2HR	Wind	1,000	-	-	550	200	350		2,100
Shift Peak - 2HR	Solar	-	-	750	200	0	950		1,900
Shift Peak - 2HR	CT	-	-	588	392	196	-		1,176
Shift Peak - 2HR	Aero	-	-	-	-	-	-		-
Shift Peak - 2HR	Recip	-	-	-	-	-	-		-
Shift Peak - 2HR	CC	-	-	-	-	-	-		-
Delta	Standalone Storage	150	-	-	-	-	(50)	-	100
Delta	Wind	-	-	(150)	(100)	50	-	-	(200)
Delta	Solar	-	-	150	100	0	100	-	350
Delta	CT	-	(392)	392	(196)	196	-	-	-
Delta	Aero	-	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	-	(100)
Delta	CC	-	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. This result is directly opposite the previous scenario—and for the same reasons. Moving the peak earlier in the day accentuates the advantages of solar, and correspondingly, storage. Similar to (although opposite) the change seen in shifting the peak later in the day, the model slightly reduced the overall level of gas-fired generation in this case, likely due to the increased firm capacity provided by solar and storage.

VII. REVISED COMANCHE 3 COSTS AND OPERATIONAL ASSUMPTIONS

Q. HOW WERE THE MODIFIED COMANCHE 3 COSTS AND AVAILABILITY SENSITIVITY SCENARIOS DEVELOPED?

A. The Company developed revised costs and availability assumptions for Comanche 3 using the actual costs for 2010-2020 as described in the Staff Report.[17] Specifically, the Company changed the Base Case assumption for fixed O&M for Comanche 3 when running on coal and not restricted in output to be $34.8 million in 2020, and escalated this value by the inflation rate through the life of the resource. The Company also adjusted the availability of the unit downward to match an equivalent availability factor ("EAF") of 71.2 percent through the combination of scheduled maintenance and forced outage rate, when not otherwise restricted to a capacity factor of 33 percent. All SCC and \$0/CO_2 scenarios were rerun using these new assumptions to generate new capacity expansion plans and production costs.

Q. HOW DO THE VALUES USED IN SUPPLEMENTAL DIRECT FOR O&M AND EAF COMPARE WITH THE VALUES USED IN THE DIRECT CASE?

A. Table JTL-SD-11 below compares the O&M and EAF assumptions in both Direct and Supplemental Direct.

[17] "Staff Report, Volume 1, Confidential Version," March 1, 2021, filed in Proceeding No, 20I-0437E.

TABLE JTL-SD-11

	Direct Case	Supplemental Direct
EAF (%)	88	71.2
O&M ($M, 2020)	$22.6	$34.8

Q. WERE ALL ANALYSES FROM PHASE I REPEATED?

A. No, only the $0/$CO_2$ capacity expansion with $0/$CO_2$ dispatch and the SCC capacity expansion with $0/$CO_2$ dispatch runs were performed, consistent with Commission directives in Decision No. C21-0395-I.

Q. WERE COST EVALUATIONS PERFORMED?

A. Yes, the full costs were evaluated, including the step of switching 50 percent of the generic resources modeled as ECC costs into capital revenue requirements representation, so a valid comparison can be made to the runs using base assumptions. Rate impact calculations were not performed due to time restrictions.

Q. WHAT WERE THE CHANGES IN THE SCC OPTIMIZED SCENARIOS?

A. The updated results, shown in the same format as Table 2.13-2 of Attachment AKJ-2 (Volume 2, Technical Appendix), for the SCC optimized scenarios are shown in Table JTL-SD-12 below. Additionally, Table JTL-SD-13 shows the deltas between the Comanche 3 Cost/Availability sensitivity to the runs with Base Case assumptions.

TABLE JTL-SD-12

Staff Com 3 Costs:
SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	**-71%**	**-88%**	**-81%**	**-87%**	**-88%**	**-81%**	**-84%**	**-81%**
CO2 Reduction Efficiency ($/ton)	-	$ 53	$ 39	$ 35	$ 41	$ 37	$ 32	$ 26
PVRR Utility Cost 2021-2055 ($M)	$ 39,136	$ 39,682	$ 39,481	$ 39,773	$ 39,622	$ 39,512	$ 39,449	$ 39,570
PVRR Utility Cost Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 217	$ 117	$ 262	$ 235	$ 164	$ 154	$ 253
2021-2040 ($M)	$ -	$ 793	$ 425	$ 648	$ 716	$ 420	$ 358	$ 486
2021-2055 ($M)	$ -	$ 546	$ 345	$ 637	$ 486	$ 376	$ 313	$ 434
NPV CO2 2021-2055 ($M)	$ 8,334	$ 6,242	$ 6,759	$ 6,175	$ 6,160	$ 6,663	$ 6,556	$ 6,356
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,470	$ 45,924	$ 46,240	$ 45,948	$ 45,781	$ 46,174	$ 46,005	$ 45,926
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ (61)	$ (87)	$ (237)	$ (145)	$ (132)	$ (166)	$ (349)
2021-2040 ($M)	$ -	$ (1,014)	$ (863)	$ (1,240)	$ (1,176)	$ (966)	$ (1,135)	$ (1,206)
2021-2055 ($M)	$ -	$ (1,546)	$ (1,230)	$ (1,522)	$ (1,689)	$ (1,296)	$ (1,466)	$ (1,544)
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 4,496	$ 6,182	$ 5,183	$ 5,271	$ 5,894	$ 4,940	$ 5,243	$ 4,994
Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
Phase II 2030 Resource Need (MW)	(1,747)	(2,752)	(2,252)	(1,747)	(2,247)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,800	2,400	2,050	2,350	2,400	2,100	2,200	2,150
Utility-Scale Solar	1,200	1,500	1,350	1,500	1,550	1,350	1,550	1,350
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	400	450	400	450	500	400	450	400
Firm Dispatchable	1,276	2,213	1,764	1,176	1,764	1,372	1,233	1,372

TABLE JTL-SD-13

Delta, Staff Com 3 Costs v. Base:
SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan

\	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-2%	0%	0%	0%	0%	0%	0%	0%
CO2 Reduction Efficiency ($/ton)	-	$ 8	$ (6)	$ 2	$ 6	$ 4	$ 1	$ 2
PVRR Utility Cost 2021-2055 ($M)	$ 190	$ 96	$ 29	$ 286	$ 92	$ 200	$ 113	$ 111
PVRR Utility Cost Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 3	$ (32)	$ (9)	$ 22	$ 1	$ (16)	$ 9
2021-2040 ($M)	$ -	$ (62)	$ (138)	$ 20	$ (11)	$ 34	$ (69)	$ (31)
2021-2055 ($M)	$ -	$ (94)	$ (161)	$ 97	$ (98)	$ 10	$ (77)	$ (79)
NPV CO2 2021-2055 ($M)	$ (265)	$ (59)	$ (118)	$ (93)	$ (130)	$ (129)	$ (65)	$ (128)
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (76)	$ 37	$ (89)	$ 193	$ (38)	$ 71	$ 48	$ (16)
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 44	$ (11)	$ 44	$ 43	$ 32	$ 26	$ 33
2021-2040 ($M)	$ -	$ 113	$ (21)	$ 164	$ 92	$ 138	$ 100	$ 75
2021-2055 ($M)	$ -	$ 113	$ (14)	$ 268	$ 37	$ 146	$ 123	$ 59
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 214	$ (198)	$ (631)	$ (247)	$ 224	$ 93	$ (135)	$ (366)
Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II 2030 Resource Need (MW)	-	-	-	(0)	-	-	-	-
Resource Additions 2021-2030 (Nameplate MW)								
Wind	150	50	(250)	50	50	250	(100)	(200)
Utility-Scale Solar	50	(50)	(200)	-	-	100	-	(200)
Distributed Solar	-	-	-	-	-	-	-	-
Storage	-	-	-	-	100	-	50	-
Firm Dispatchable	-	20	(196)	(392)	139	(133)	(43)	139

Q. WHAT WERE THE CHANGES IN THE SCC OPTIMIZED SCENARIOS?

A. The updated results, shown in the same format as Table 2.13-2 of Attachment AKJ-2 (Volume 2, Technical Appendix) data, for the $0/$CO_2$ optimized scenarios are shown below in Table JTL-SD-14. Additionally, Table JTL-SD-15 shows the deltas between the Comanche 3 Cost/Availability sensitivity to the runs with Base Case assumptions.

TABLE JTL-SD-14

Staff Com 3 Costs:
$0/ton Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-64%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
CO2 Reduction Efficiency ($/ton)	-	$ 45	$ 41	$ 26	$ 29	$ 31	$ 23	$ 23
PVRR Utility Cost 2021-2055 ($M)	$ 38,507	$ 38,950	$ 39,103	$ 39,054	$ 38,885	$ 39,057	$ 38,919	$ 39,084
PVRR Utility Cost Delta vs. $0/ton 1								
2021-2030 ($M)	$ -	$ 173	$ 160	$ 185	$ 153	$ 164	$ 124	$ 233
2021-2040 ($M)	$ -	$ 695	$ 672	$ 563	$ 591	$ 582	$ 470	$ 615
2021-2055 ($M)	$ -	$ 443	$ 597	$ 548	$ 379	$ 550	$ 413	$ 577
NPV CO2 2021-2055 ($M)	$ 8,950	$ 7,034	$ 7,017	$ 6,837	$ 6,937	$ 6,921	$ 6,938	$ 6,631
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,457	$ 45,984	$ 46,120	$ 45,892	$ 45,822	$ 45,978	$ 45,857	$ 45,715
PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
2021-2030 ($M)	$ -	$ (90)	$ (104)	$ (294)	$ (207)	$ (197)	$ (237)	$ (418)
2021-2040 ($M)	$ -	$ (959)	$ (989)	$ (1,293)	$ (1,160)	$ (1,173)	$ (1,279)	$ (1,430)
2021-2055 ($M)	$ -	$ (1,472)	$ (1,337)	$ (1,565)	$ (1,634)	$ (1,479)	$ (1,600)	$ (1,741)
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 2,447	$ 3,792	$ 4,342	$ 3,195	$ 3,395	$ 3,856	$ 3,515	$ 3,856
Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
Phase II 2030 Resource Need (MW)	(1,747)	(2,752)	(2,252)	(1,747)	(2,247)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,000	1,000	1,450	1,000	1,000	1,450	1,150	1,450
Utility-Scale Solar	-	550	1,100	900	600	1,050	1,050	1,050
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	50	50	50	50	50	50	50	50
Firm Dispatchable	1,764	2,940	2,352	1,764	2,352	1,764	1,668	1,764

TABLE JTL-SD-15

Delta, Staff Com 3 Costs v. Base: SCC Optimized Portfolios $0/ton 8760-dispatch
50% ownership

Preferred Plan (SCC 7)

\	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-2%	0%	0%	0%	0%	0%	0%	0%
CO2 Reduction Efficiency ($/ton)	-	$ 8	$ (6)	$ 2	$ 6	$ 4	$ 1	$ 2
PVRR Utility Cost 2021-2055 ($M)	$ 190	$ 96	$ 29	$ 286	$ 92	$ 200	$ 113	$ 111
PVRR Utility Cost Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 3	$ (32)	$ (9)	$ 22	$ 1	$ (16)	$ 9
2021-2040 ($M)	$ -	$ (62)	$ (138)	$ 20	$ (11)	$ 34	$ (69)	$ (31)
2021-2055 ($M)	$ -	$ (94)	$ (161)	$ 97	$ (98)	$ 10	$ (77)	$ (79)
NPV CO2 2021-2055 ($M)	$ (265)	$ (59)	$ (118)	$ (93)	$ (130)	$ (129)	$ (65)	$ (128)
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (76)	$ 37	$ (89)	$ 193	$ (38)	$ 71	$ 48	$ (16)
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 44	$ (11)	$ 44	$ 43	$ 32	$ 26	$ 33
2021-2040 ($M)	$ -	$ 113	$ (21)	$ 164	$ 92	$ 138	$ 100	$ 75
2021-2055 ($M)	$ -	$ 113	$ (14)	$ 268	$ 37	$ 146	$ 123	$ 59
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 214	$ (198)	$ (631)	$ (247)	$ 224	$ 93	$ (135)	$ (366)
Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II 2030 Resource Need (MW)	-	-	-	(0)	-	-	-	-
Resource Additions 2021-2030 (Nameplate MW)								
Wind	150	50	(250)	50	50	250	(100)	(200)
Utility-Scale Solar	50	(50)	(200)	-	-	100	-	(200)
Distributed Solar	-	-	-	-	-	-	-	-
Storage	-	-	-	-	100	-	50	-
Firm Dispatchable	-	20	(196)	(392)	139	(133)	(43)	139

Q. HOW DID THE COMPANY EVALUATE THE IMPACTS OF PERIODS OF ECONOMIC SHUTDOWN AND DISPATCHING UNDER SEASONAL PARAMETERS?

A. To test the impact of economic operations, the Company adjusted Comanche 3 to not be “must run” and be dispatched economically starting in 2025 for all scenarios. Commitment parameters such as minimum up and down times (once committed) and start up fuel consumption were kept at the base assumptions. For the conversion to gas scenarios, the requirement to be fully committed for the winter and summer peak seasons was maintained, with the unit being committed economically in all other months. To test the impact of seasonal operations, when burning coal, the unit was placed out of service in the months of March-May and September-November beginning in 2025. These options were modeled separately (not combined) and the impacts were evaluated for both the Preferred Plan (SCC 7) and the scenario where both Pawnee and Comanche 3 are retired early in 2028 and 2029, respectively (SCC 2).

Q. WHAT WERE THE MODELED RESULTS OF THIS ANALYSIS?

A. Overall, the change in operations had minimal impact on the expansion plans, and generally led to an increase in present value of revenue requirements ("PVRR") and a modest decrease in total costs when including the cost of carbon at the SCC, as shown below in Table JTL-SD-16.

TABLE JTL-SD-16

Staff Com 3 Costs:
Test Econ and Seas Com 3 Dispatch
SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan

Portfolio	SCC 2	SCC 2	SCC 2	SCC 7	SCC 7	SCC 7
Resource Need:	CEP	CEP	CEP	CEP Preferred	CEP Preferred	CEP Preferred
Pawnee Action:	Retire EOY 2028	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027
Comanche 3 Action:	Retire EOY 2029	Retire EOY 2029 Seas 2025+	Retire EOY 2029 Econ 2025+	Retire EOY 2039 Red Ops	Retire EOY 2029 Seas 2025+	Retire EOY 2029 Econ 2025+
2030 CO2 % Reduction	**-88%**	**-88%**	**-88%**	**-84%**	**-84%**	**-85%**
PVRR Utility Cost 2021-2055 ($M)	$ 39,682	$ 39,630	$ 39,700	$ 39,449	$ 39,581	$ 39,556
PVRR Utility Cost Delta vs. SCC 2/7						
2021-2030 ($M)	$ 15,507	$ 24	$ 31	$ 15,444	$ 67	$ 84
2021-2040 ($M)	$ 27,594	$ (44)	$ 30	$ 27,159	$ 177	$ 148
2021-2055 ($M)	$ 39,682	$ (52)	$ 18	$ 39,449	$ 133	$ 107
NPV CO2 2021-2055 ($M)	$ 6,242	$ 6,237	$ 6,105	$ 6,556	$ 6,410	$ 6,345
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 45,924	$ 45,867	$ 45,805	$ 46,004	$ 45,991	$ 45,900
PVRR Utility Cost + NPV CO2 Delta						
2021-2030 ($M)	$ 20,329	$ (49)	$ (110)	$ 20,225	$ (35)	$ (73)
2021-2040 ($M)	$ 33,495	$ (49)	$ (106)	$ 33,374	$ 31	$ (62)
2021-2055 ($M)	$ 45,924	$ (57)	$ (119)	$ 46,004	$ (13)	$ (104)
Phase II 2030 Resource Need (MW)	(2,752)	(2,752)	(2,752)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)						
Wind	2,400	2,300	2,350	2,200	2,350	2,350
Utility-Scale Solar	1,500	1,500	1,550	1,550	1,600	1,550
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158
Storage	450	500	450	450	450	400
Firm Dispatchable	2,213	2,156	2,156	1,233	1,176	1,176

Q. WHAT ARE THE OPERATIONAL IMPACTS OF SEASONAL OPERATIONS?

A. In general, the Company believes that leaving the commitment of the unit to the system operators to manage in the most economic manner, subject to targeted objectives (i.e., carbon production, total generation, etc.) rather than forced calendar-based schedules is preferable. The Company has effectively managed to limitations in the past to meet emission limits, coal delivery restrictions, or remaining run hours to a required outage. By managing to the desired result and not limiting the Company's options, the utility of the facilities can be maximized.

Q. WHAT ARE THE OPERATIONAL IMPACTS OF ECONOMIC DISPATCH?

A. In general, the Company supports reducing operational limitations on baseload units across all of its jurisdictions and has actively worked to increase flexibility on coal units both in Colorado and elsewhere. The Company will manage units within applicable constraints throughout the year. These adders effectively reprioritize the stack of generation economically when making daily commitment and dispatch decisions. With Comanche 3 set up as an energy limited resource, the Company can meet reliability and economic needs at the most opportune times.

Q. HOW DO YOU INTERPRET THE OVERALL RESULTS OF THE COMANCHE 3 COSTS AND AVAILABILITY SENSITIVITY ANALYSIS?

A. A summary of some of the key data from this analysis is provided in the three sub-tables of Table JTL-SD-17 below. This summary, as well as the detailed tables above, show that using the historically derived costs and availability mostly results in increased costs across all of portfolios. The composition of the Preferred Plan and the carbon reduction does not materially change. This sensitivity case serves to reinforce the Company's choice of Preferred Plan and show it is robust given a range of assumptions on the future cost and performance of Comanche 3.

1 **TABLE JTL-SD-17**

SCC Preferred Plan: Differences between Base Case and Supplemental Direct Cases

SUBTABLE 1:

	PVRR	Delta
Base Case/Direct Testimony*	39,336	
Historic-based/Staff Cost and Availability Assumptions	39,449	113

SUBTABLE 2:

	PVRR	Delta	CO2 Emissions (% Reduction since 2005)
Historic-based/Staff Cost and Availability Assumptions	39,449		-88%
Add Economic Dispatch	39,556	107	-85%
Add Seasonal Dispatch	39,581	133	-84%

SUBTABLE 3:

	Capacity Expansion in RAP (MW)			
	Wind	Utility-Scale Solar	Storage	Firm Dispatchable
Base Case/Direct Testimony*	2,300	1,550	400	1,276
Historic-based/Staff Cost and Availability Assumptions	2,200	1,550	450	1,233
Economic Dispatch	2,350	1,550	400	1,176
Seasonal Dispatch	2,350	1,600	450	1,176

*As corrected in this Supplemental Direct Filing

VIII. INCREASED CSG CAPACITY

Q. HOW WAS THE INCREASE IN CSG CAPACITY MODELED?

A. The Company created the scenario using the baseload plan from the Company's Preferred Plan (SCC 7) with Pawnee converted to natural gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The Base Case forecasted CSG capacity was increased by 50 MW a year beginning in 2023 through 2026 for a total of an additional 200 MW. All other data in the model was kept the same as what was filed in the Company's direct case, and a new capacity expansion plan was created. The same estimated $/MWh cost for CSG in the Base Case was used for the incremental costs.

Q. WHAT WERE THE RESULTS OF INCREASING CSG CAPACITY BY 200 MW?

A. The model selected an optimized RAP expansion plan that selected 200 MW less large scale solar, 100 MW less reciprocating engine capacity, and 50 MW more storage. The year-by-year differences in the "Increased CSG" plan versus SCC 7 are shown in Table JTL-SD-18 below:

TABLE JTL-SD-18

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Add 200 MW CSG	Standalone Storage	250	-	-	-	-	200	450
Add 200 MW CSG	Wind	1,000	-	100	650	150	400	2,300
Add 200 MW CSG	Solar	-	-	450	150	0	750	1,350
Add 200 MW CSG	CT	-	196	392	588	-	-	1,176
Add 200 MW CSG	Aero	-	-	-	-	-	-	-
Add 200 MW CSG	Recip	-	-	-	-	-	-	-
Add 200 MW CSG	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	50	-	-	-	-	-	50
Delta	Wind	-	-	(50)	-	-	50	-
Delta	Solar	-	-	(150)	50	(0)	(100)	(200)
Delta	CT	-	(196)	196	-	-	-	-
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. When additional CSG capacity is added in the early-to-mid 2020s, it replaces the large-scale solar that was originally selected in 2027 and beyond on a 1-to-1 basis. This is expected, as CSG and utility scale solar are very similar in the "benefits" provided to the system. The primary difference between the two is that CSG generally has a lower capacity factor and higher cost. A single additional battery was added in 2025, likely to match the timing of the CSG capacity, which partially offsets the firm dispatchable capacity in the late 2020s. There is no clear justification for the additional storage and reduction in firm dispatchable capacity.

Given that these are changing a single generic resource of each technology and that the changes do not occur simultaneously, it is just as likely that this is a result of normal variance in the model solution process than a meaningful result.

Q. WHAT WERE THE COST AND CARBON IMPACTS OF ADDING INCREMENTAL CSG CAPACITY?

A. A cost and carbon comparison analysis was conducted for the impacts of incremental CSG capacity, similar to the DR analysis which I discuss in the next section of my Supplemental Direct Testimony. For the CSG analysis, however, the cost of the resource was embedded in the EnCompass modeling. Overall, the CSG results in an incremental PVRR cost of $215 million on a NPV basis. When the SCC is included there is a net cost of $183 million. The overall carbon reductions by adding the CSG are almost all driven by the assumption of earlier in-service dates for the CSG versus the utility-scale solar that it offset, resulting in time-value-of-money savings for the carbon reductions simply due to timing. For the periods beyond 2027 when the total combined solar additions are essentially the same, there is no material difference in carbon emissions. The results of the cost analysis are shown below in Table JTL-SD-19.

TABLE JTL-SD-19

	$2021 Millions
NPV EnCompass Cost (Savings)	$215
NPV CO2$, SCC Cost (Savings)	($32)
PVRR + NPV CO2 Cost (Savings)	$183

IX. INCREASED DEMAND RESPONSE CAPACITY

Q. HOW WAS THE INCREASED DEMAND RESPONSE CAPACITY MODELED?

A. The Company created the scenario using the baseload plan from the Company's Preferred Plan (SCC 7) with Pawnee converted to gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The DR capacity was increased by 50 MW per year beginning in 2023 through 2026 for a total of an additional 200 MW. All other data in the model was kept the same as what was filed in the Company's direct case, and a new capacity expansion plan was created.

Mr. Ihle discusses the policy implications and caveats with the capacity and budget forecasted provided in support of this analysis.

Q. PLEASE SUMMARIZE THE COMPANY'S FORECAST OF DEMAND RESPONSE IN THE BASE CASE AND IN THE SUPPLEMENTAL MODELING.

A. Table JTL-SD-20 below compares the Company's annual, cumulative DR capacity forecast by year for both the Base Case and Supplemental Direct forecasts.

Table JTL-SD-20

Year	**Base Case** (MW)	**Supplemental** (MW)
2021	527	527
2022	527	527
2023	561	611
2024	561	661
2025	561	711
2026	586	786
2027	586	786
2028	586	786
2029	586	786
2030	606	806

Q. WHAT PROGRAMS CONSTITUTED THE ADDITIONAL 200 MW OF DR CAPACITY?

A. The Company created a potential alternate portfolio composed of additional participation in existing or proposed programs, as well as potential new program offerings. The composition of the portfolio is shown below in Table JTL-SD-21. The shaded programs are potential new offerings.

TABLE JTL-SD-21

Program	AC Rewards: Res + Biz	AC Rewards	Saver's Switch	Battery Connect	CPP	PPR	ISOC	EV Programs - V2G	EV Programs - V1G	Water Heaters	Behavioral DR	Peak Day Partners	Total
New 2023 MW	15	0	2	5	3	1.5	0	0	13	0.5	3	7	50
New 2024 MW	15	0	3	5	3	6.5	5	0	4	0.5	3	5	50
New 2025 MW	10	8	3	5	3	7	5	1	3	0	3	2	50
New 2026 MW	10	7	2	5	3	5	0	1	5	0	6	6	50

Q. WERE ANY COST ASSUMPTIONS MADE REGARDING THESE PROGRAMS?

A. Yes. An estimated budget for the incremental portfolio is an incremental $15.8 million per year (2021 dollars).

Q. WHAT WERE THE RESULTS OF INCREASING DR CAPACITY BY 200 MW?

A. The model selected an optimized RAP expansion plan with approximately 300 MW less gas-fired capacity and one more wind unit. The year-by-year differences in the "Increased DR" plan versus SCC 7 are shown in Table JTL-SD-22 below:

TABLE JTL-SD-22

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Add 200 MW DR	Standalone Storage	200	-	-	-	-	200	400
Add 200 MW DR	Wind	1,000	-	150	650	150	400	2,350
Add 200 MW DR	Solar	-	-	600	150	0	800	1,550
Add 200 MW DR	CT	-	-	-	980	-	-	980
Add 200 MW DR	Aero	-	-	-	-	-	-	-
Add 200 MW DR	Recip	-	-	-	-	-	-	-
Add 200 MW DR	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	-	-	-	-	-	-	-
Delta	Wind	-	-	-	-	-	50	50
Delta	Solar	-	-	-	50	-	(50)	0
Delta	CT	-	(392)	(196)	392	-	-	(196)
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. When additional DR capacity is added, it reduces the capacity need and less firm dispatchable resources are selected.

Q. HOW DOES THE INCREASED DR PORTFOLIO COMPARE IN COSTS AND CARBON EMISSIONS?

A. The incremental DR program costs were not included directly in the EnCompass model, as they are fixed costs and do not affect either the capacity expansion or dispatch process. The scenario including the additional DR produced slightly less carbon emissions, but averaged only 21,000 tons less carbon per year for 2023-2050. The Company performed a simple spreadsheet calculation of the estimated costs of the program compared to the modeled EnCompass savings, including the NPV of carbon reductions using the SCC. As with the previous analyses, the capital revenue requirements representation was omitted. The results of this analysis are shown below in Table JTL-SD-23 below. While this scenario shows savings, Company witness Mr. Ihle describes some of the policy considerations associated with this scenario.

TABLE JTL-SD-23

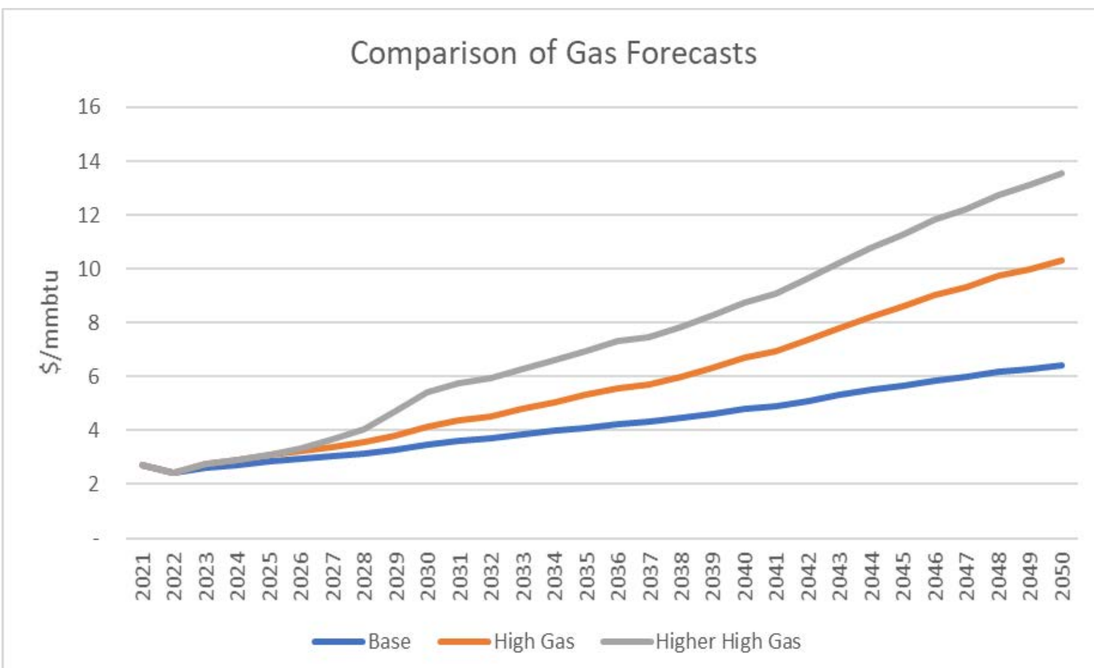
	$2021 Millions
NPV EnCompass Cost (Savings)	($258)
NPV Est. Program Costs (Savings)	$237
Net PVRR Cost (Savings)	($21)
NPV CO2$, SCC Cost (Savings)	($22)
PVRR + NPV CO2 Cost (Savings)	($42)

X. HIGHER HIGH NATURAL GAS COST FORECAST

Q. HOW WAS THE HIGHER HIGH NATURAL GAS COST SCENARIO MODELED?

A. The Company created the scenario using the baseload plan from the Company's Preferred Plan (SCC 7) with Pawnee converted to natural gas and Comanche 3 on limited operations beginning in 2030 and retiring in 2039. The Company adjusted the High Gas forecast filed in its direct case to have double the "high" escalation rate for 2026 through 2030. A comparison of the Base Case, High, and Higher High gas forecasts is shown below in Figure JTL-SD-3. All other data in the model was kept the same as what was filed in the Company's direct case, and a new capacity expansion plan was created.

FIGURE JTL-SD-3



Q. WHAT WERE THE RESULTS OF THE HIGHER HIGH NATURAL GAS SCENARIO?

A. The model selected an optimized RAP expansion plan that selected 100 MW more storage, 350 MW more wind, 150 MW more solar, and 100 MW less gas-fired reciprocating engine capacity. The year-by-year differences in the Higher High Gas plan versus SCC 7 are shown in Figure JTL-SD-4 below:

FIGURE JTL-SD-4

	Plan Nameplate (MW)	2025	2026	2027	2028	2029	2030	Total
SCC 7	Standalone Storage	200	-	-	-	-	200	400
SCC 7	Wind	1,000	-	150	650	150	350	2,300
SCC 7	Solar	-	-	600	100	0	850	1,550
SCC 7	CT	-	392	196	588	-	-	1,176
SCC 7	Aero	-	-	-	-	-	-	-
SCC 7	Recip	-	-	-	-	100	-	100
SCC 7	CC	-	-	-	-	-	-	-
Higher High Gas	Standalone Storage	350	-	-	-	-	150	500
Higher High Gas	Wind	1,000	100	150	850	50	500	2,650
Higher High Gas	Solar	-	50	800	0	50	800	1,700
Higher High Gas	CT	-	196	392	588	-	-	1,176
Higher High Gas	Aero	-	-	-	-	-	-	-
Higher High Gas	Recip	-	-	-	-	-	-	-
Higher High Gas	CC	-	-	-	-	-	-	-
Delta	Standalone Storage	150	-	-	-	-	(50)	100
Delta	Wind	-	100	-	200	(100)	150	350
Delta	Solar	-	50	200	(100)	50	(50)	150
Delta	CT	-	(196)	196	-	-	-	-
Delta	Aero	-	-	-	-	-	-	-
Delta	Recip	-	-	-	-	(100)	-	(100)
Delta	CC	-	-	-	-	-	-	-

Q. HOW DO YOU INTERPRET THIS RESULT?

A. With higher natural gas prices, gas-fired resources are less cost-effective. Therefore, incremental wind and solar were added to further reduce the amount of generation provided by fossil-fuel resources, and the capacity expansion plan selected slightly less gas-fired capacity as well. The storage was likely added to better utilize the incremental renewable energy by reducing load-driven curtailments and moving the energy to time periods of greater need. The Company notes, however, that this scenario results in higher curtailments than the Preferred Plan, ranging from around 500 to 1,000 GWh more per year in 2028 and beyond. It is also notable that even with this very high gas scenario, the model is selecting all of the gas CT resources it selected in the Company's Preferred Plan. While these resources generate less under the scenario (the gas fleet net capacity factor in 2030 goes from 13.9 percent to 12.7 percent), the installed capacity is exactly the same under both this scenario and SCC 7 at 1,176 MW.

Q. HOW DOES THE HIGHER HIGH GAS FORECAST PORTFOLIO COMPARE IN COSTS AND CARBON EMISSIONS?

A. The scenario with the higher high gas cost forecast produced less carbon emissions, averaging around 200,000 tons less carbon per year for 2021-2050. As previously mentioned in the description of the cost impact analysis for the Reduced Lifetime scenario, the costs for the generic resources were left as ECC representation. The results of this analysis are shown below in Table JTL-SD-24 below.

TABLE JTL-SD-24

	$2021 Millions
NPV EnCompass Cost (Savings)	$1,782
NPV CO2$, SCC Cost (Savings)	($196)
PVRR + NPV CO2 Cost (Savings)	$1,586

XI. SUMMARY OF ANALYSIS

Q. WHAT IN YOUR OPINION ARE THE KEY IMPLICATIONS OF THIS SET OF REQUESTED SCENARIOS?

A. The Company believes that these scenarios provide a useful set of "stress tests" to benchmark our Preferred Plan. The Company—after reviewing the results of these stress tests—continues to believe that its Preferred Plan provides the best path forward for this proceeding. No scenario here resulted in material additional reductions of carbon dioxide emissions; further, the scenarios generally supported the Preferred Plan's buildout of a portfolio of solar, storage, wind, and firm dispatchable natural gas capacity in the RAP, albeit at somewhat different levels across the scenarios.

I note that two scenarios that test the model's selection of generic gas resource additions, the reduced lifetime scenario and the higher high gas scenario, still resulted in generic gas additions. The Company recognizes that there are concerns around committing to potentially new natural gas resources, and feels that these runs as requested by the Commission should provide some degree of reassurance that new gas resources can be consistent with economic, reliable plans that also meet rigorous emission reduction objectives.

The results of the modeling also universally continued to build large amounts of wind and solar. Overall, we appreciate the Commission's interest in testing alternative assumptions and stress-testing the Preferred Plan. The requests of the Commission tested and confirmed the Company's proposed Preferred Plan in useful ways.

XII. MODELING ERROR AND ASSOCIATED CORRECTIONS TO THE COMPANY'S DIRECT CASE

Q. PLEASE DESCRIBE THE MODELING ERROR THE COMPANY FOUND AND IS CORRECTING ALONG WITH ITS SUPPLEMENTAL DIRECT TESTIMONY FILING.

A. During the creation of the final EnCompass database for the Phase I filing in January 2021, one data file was inadvertently left out of the merging process and not input into the database. This file contained the final updated financial data for the baseload units, including capital revenue requirements and O&M forecasts. Since the file was not uploaded, the data for these items remained as the December 2020 vintage estimates. One additional data item in this file was setting the early retirement date for Comanche 3 to the end of 2029 in the scenarios where it was retired in the late 2020s. In the older vintage file, it was incorrectly set to the end of 2028.

Q. HOW DOES THIS DATA ERROR AFFECT THE RESULTS?

A. The data is generally fixed cost data that affects the annual and present value costs of the scenarios, but not the expansion plans. There are two scenarios where Comanche 3 is retired early (i.e., Scenarios 2 and 5), where the change in retirement date by one year affects the expansion plans.

Q. HOW DID THE COMPANY IDENTIFY THE ERROR?

A. During setup of the modeling for the additional analyses ordered by the Commission for Supplemental Direct Testimony, the Company examined the costs for Comanche 3 in the model to compare with the 2010-2020 actual data requested by the Commission to be used in some of the new analysis. It was discovered that the data in the model did not match the values the Company expected to be there.

Q. PLEASE DESCRIBE HOW THE COMPANY HAS CORRECTED THE ERROR.

A. The Company uploaded the correct file before conducting the Supplemental Direct analysis, and also re-ran the modeling in the direct case with the error corrected. The Company is filing corrected versions of the relevant Phase I Direct Testimony and Attachments concurrent with the Supplemental Direct filing. The Company has also made a commitment to update relevant discovery requests from parties as soon as is practicable.

Q. WHAT DOCUMENTS FROM THE COMPANY'S DIRECT CASE ARE BEING CORRECTED?

A. A full list of the corrected documents is provided in the Notice filed along with the corrected testimony and attachments.

Q. DOES THE ERROR RESULT IN SIGNIFICANT CHANGES TO THE COMPANY'S PHASE I PORTFOLIO ANALYSIS OR ITS PREFERRED PLAN?

A. No. The changes are mostly related to fixed costs and affect all scenarios similarly within a band of around $0-$150 million on a NPV basis. The corrected cost values do not change the Company's choice in preferred baseload scenario, nor the composition of the Preferred Plan. Overall, the changes are less than one-half of one percent of the total NPVs of the plans, and in the Company's opinion do not materially change the conclusions or key takeaways from the analyses.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	) PROCEEDING NO. 21A-21A-0141E

AFFIDAVIT OF JON T. LANDRUM
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Jon T, Landrum, being duly sworn, state that the Supplemental Direct Testimony was prepared by me or under my supervision, control, and direction; that the Supplemental Direct Testimony is true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 12th day of August, 2021.

Jon T Landrum

Jon T. Landrum
Manager, Resource Planning Analytics

Subscribed and sworn to before me this 12th day of August, 2021.

Holly Mashburn

Notary Public

My Commission expires April 13, 2025

Holly A. Mashburn
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20214014663
MY COMMISSION EXPIRES April 13, 2025